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A Sensitivity Analysis of the NPC Study of Tight Gas

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INTRODUCTION AND SUMMARY

In 1980, the National Petroleum Council (NPC) published the results of a two-year, multi-company study of unconventional natural gas.[1] It concluded that low permeability, "tight" gas reservoirs have significant potential for the U.S. domestic energy production. The size of this potential depends on the geological assessment, extraction technology performance, and production economics. The NPC assessment remains the most exhaustive and credible estimate of tight gas potential since its publication.

The Tight Gas Analysis System (TGAS) is a joint project of the Gas Research Institute and the U.S. Department of Energy. It is designed to "automate" the NPC analytical approach to tight gas assessment by creating a comprehensive model that will permit sensitivity analysis of key assumptions, updating as new data become available, and timely reinterpretation of results in light of changing technology and economics.

The TGAS model also introduces the concept of economic rent which was not explicitly reported in the NPC assessment. Economic rent is defined as the difference between the minimum required selling price for producing an incremental unit of gas (i.e., marginal cost) and current sales price. This approach assumes that all costs remain constant in real terms throughout the development of the project. This minimum required selling price is defined as that gas price (per Mcf) which equates the present value of the after-tax net cash flows from a project to zero; that is, the minimum price that fully reimburses all costs, including the risk adjusted cost of capital and taxes. Net cash flow is evaluated at the full cost of exploration and development; all transfer payments to government and royalty holders are included in this price. The reader should note that portions of this economic rent may be distributed among other participants in gas development including drillers, suppliers, royalty holders, and taxing agencies. However, if the NPC assumption that costs remain constant is retained, then economic rent is a useful index of economic attractiveness.

If economic rent is a leading criterion for deciding which basins to explore and develop, this analysis indicates that near-term development potential of the NPC Base case may lie in the blanket sand portion of the Piceance and Uinta basins, and in the Cotton Valley and Edwards Lime Trends. Current industry activity confirms this assessment.

The study focuses on the economics of the NPC Base case by analyzing the effects of reducing industry's risk premium. Geology or technology variables were not manipulated since they will be the subjects of later TGAS analyses. The analysis showed that the benefits of risk reduction lie primarily in a greater amount of gas forecast to be available at prices below the current incentive price for tight gas.

METHODOLOGY

The TGAS system is divided into four submodels: (a) geology, (b) technology, (c) exploration and economics; and (d) production timing. This paper reports on studies which use the exploration and economics submodel. The following data from the NPC's 1980 report were accepted without change:

- Costs: the analysis was conducted in constant 1982 dollars. NPC's estimates of the costs of drilling, stimulation, operations, and compression were adjusted to $1982 by a method developed by Ovid Baker was used to convert NPC's costs which are stated as "January 1979" costs to 1982 dollars.[2]
- Geology, including area, thickness, permeability, gas-filled porosity, gas in

References and illustrations at end of paper.

place, and recoverable gas from actual wells.

- Technology, including fracture length, conductivity, well performance and well spacing.

The exploration and economics submodel performs the following functions:

- The resource is analyzed by "basic units" defined as a formation within a subbasin within a basin (there are a total of 82 such basic units).

- Each basic unit is divided into permeability grades ranging from 0.3 to 0.00001 Md. There are from five to ten grades within each basic unit.

- The marginal cost of developing each permeability grade is assessed by using a numerical algorithm which finds the price per thousand cubic feet (Mcf) which sets the after-tax net present value of all cash flows at zero. The required rate of return is a joint function of risk premium and the underlying costs of capital. The discount rate applied to each permeability grade is equal to the required rate of return. This is equivalent to estimating the gas price which would compensate all investment, operating, and financial costs; it may be interpreted as a minimum required selling price.

- Each basic unit is analyzed as a multi-field play, at trial gas prices ranging from $1.34 to $15.66 (based on $1-$12/Mcf suggested by NPC, as adjusted to $1982). The Monte Carlo technique used by the NPC was not used in this study. Instead, a simplified version which used the expected values of all parameters was substituted. The entire unit is drilled according to success probabilities assigned by the NPC. If a well finds hydrocarbons in a particular "field" (portion of a permeability grade), it is considered "economic" if the marginal cost is greater that the trial gas price (otherwise it is declared dry). If an exploratory well is economic, the entire field is developed. The total cash flow from dry and successful exploratory and development wells in the play is evaluated. If the present value is positive the play is considered to be economic.

- The economic rent of each basic unit is computed as the sum of the positive present values from each play at each trial price, i.e., the difference between the minimum required selling price, or full cost, and the trial price. In practice, this rent might accrue to operators, drillers, suppliers, royalty holders, taxing agencies, etc. In the context of this paper, it may be considered an index of economic attractiveness.

- Time-independent price-supply curves are constructed, aggregating to subbasin, basin, and overall levels.

This analysis is restricted to the appraised basins; no extrapolations to other basins are made. The TGAS exploration and economics model was validated against the published NPC data, including (a) the marginal cost analysis of individual permeability grades; (b) exploration and development well requirements; and (c) estimates of cost-supply relationships at the basin level.

The validation assessment indicated that the TGAS model provided a faithful replication of the NPC published results and was suitable for performing economic sensitivity studies. The NPC used cost-supply relationships as the major dependent variable in measuring the impact of technological or geological improvements. This study also uses cost-supply curves, but also adds economic rent as a second dependent variable to quantify "economic attractiveness." In addition, the basic TGAS economics model was adapted to provide insight into the role of risk in motivating industry's behavior.

NEAR TERM DEVELOPMENT POTENTIAL

To encourage near term development, the Natural Gas Policy Act allows tight gas sands to receive an incentive price (now about $5/Mcf). The NPC report provides price-supply relationships for each basin but does not give a clear indication of the relative potential for commercialization of each basin.

In order to investigate this question, the TGAS system was reconfigured to accumulate and display (for each basin) economic rent. A rational firm would seek to maximize economic rent; hence, an assessment of rents by basin is an indicator of commercialization potential.

The results of the analysis are shown in Table 1. Note that the rankings of the basins differ considerably if the criterion is recoverable gas or economic rent. In the NPC assessment, the Northern Plains has by far the greatest amount of gas available at $6.52/Mcf (77 Tcf or 46% of the total gas available at the price); however, in terms of rent per Mcf, this basin ranks sixth. The Uinta, Piceance, and Wind River Basins are the most attractive on the basis of rent, due partly to potential joint production from blanket and lenticular formations.

Due to substantial uncertainties regarding the ability to stimulate and produce lenticular formations, industry's current exploration target is largely blanket-type formations. If attention is restricted only to blanket formations, the Uinta and Piceance Basins are still most attractive on the rent/Mcf basis followed closely by the Edwards Lime and Cotton Valley Trends.

The commonly accepted explanation of industry's relative lack of interest in the Northern Great Plains is lack of pipeline service. However important this may be, the TGAS assessment of rents indicates that there are greater economic motives for drilling elsewhere, particularly in those blanket formations of the Rockies and Texas characterized by established exploration history, thick pay, high productivity and large field sizes. Since tight gas is now being developed by independents with limited resources, locational preferences should also be considered. In fact, most independents are located in Texas and do not have facilities to drill in Wyoming or Utah. Hence a combination of locational preference and economic rent can provide an explanation of the intense drilling in the Edwards Lime and Cotton Valley Trends and the relative lack of interest in the Northern Great Plains.

RISK PREMIUM VERSUS COST OF CAPITAL

The 1980 NPC analysis used a single real rate of return equal to the discount factor in present value calculations. This single rate represents the joint impact of the underlying cost of capital and risk premium. This study separated the real rate of return into component parts to illustrate the impact of risk while holding the underlying real cost of capital constant at an assumed[3] level of 8%. Risk factors of 0%, 6%, and 15% were analyzed.

The results are shown in Figure 1. If risk could be totally eliminated, a total of 177 Tcf would be available at $6.32/Mcf. This is roughly seven percent higher than the 165 Tcf available at 8% risk factor (approximately the level of risk assumed in the NPC Base case scenario). However, if the risk premium were to be 15%, only 142 Tcf would be available at $6.32/Mcf.

At the current incentive price of about $5/Mcf ($1982), some 147 Tcf would be available with Base technology in blanket sands. If risk premium could be reduced from 6% to zero, 167 Tcf would be available at the same price. Alternatively, the 147 Tcf could be produced at $4.16/Mcf ($1982), a savings of $0.84/Mcf. This would have a direct value to the consumer of approximately $17 billion. Figure 1 also demonstrates that risk reduction strategies -- such as data collection, laboratory and field research, improved reservoir diagnostic systems, and field demonstrations -- can have a significant impact at low price levels (from $2.61-6.52/Mcf). However, the level of technology assumed in NPC's Advanced case is needed to fully reap the benefits of the high-cost portion of the tight gas resource. Attainment of Advanced technology[4] would yield 231 Tcf at a 6% risk premium -- or 47 Tcf more than Base technology could be expected to yield at zero risk. (The Advanced case is displayed for reference here, although it is not analyzed in detail in the present study.)

Table 2 shows the impact of changing risk premium on basin rankings according to economic rent. An increase in risk premium raises the discount factor which, in turn, penalizes projects of long duration. Because large fields must be developed to meet deliverability criteria for periods up to 20 years, they would be hardest hit by high risk premium. A high discount factor would cut deeply into the rents of long-term projects and would encourage short-term projects. The Northern Great Plains Basin has a large number of small fields (99.9% of the fields are smaller than 50 Bcf); on the other hand, in the blanket formation of the Piceance Basin (the Corcoran-Cozette), the maximum field size is 200 Bcf. The Edwards Lime Basin has maximum field size of about 150 Bcf. Thus, high risk premium may lower the attractiveness of the basins with larger fields while raising the attractiveness of basins with smaller fields. Table 2 shows that high risk premium makes the Edwards Lime and Northern Great Plains basins more attractive while reducing the desirability of the Piceance Basin.

CONCLUSIONS

The NPC study on tight sands gas has provided an extensive data base which encourages further sensitivity analysis and evaluation. The TGAS model which is now under development is a useful tool to undertake these efforts. This paper addresses the issues of economic rent and its implication for early resource development as well as variations in the risk related rate of return on investment.

The analysis of economic rents provides insight regarding the dominance of Uinta and Piceance Basins in the Rocky Mountains and the Edwards Lime and Cotton Valley Regions of Texas where most western tight gas development is now occurring. An established exploration history, the existence of large fields and multiple overlying strata contribute to higher gas productivity per section and thus a relative abundance of attractive prospects in these regions. Thus, despite the preponderance of tight gas assumed by NPC to exist in the Northern Great Plains, analysis of economic attractiveness indicates that the greatest near-term development potential appears to be the Rockies and Texas.

The use of risk analysis in estimating resource economics is particularly important to the R&D community. To the extent that improved technology permits more successful fracture design and performance, in addition to predictability of reservoir production over time, lower required returns on investment could result to the benefit of the industry and ratepayer alike. Under the Base technology case, elimination of NPC's implicit 6% risk premium could result in 11 Tcf more gas considered economical at $6.52 in 1982 dollars. If the tight gas incentive price remains constant in real terms at about $5/Mcf (1982), the reduction in risk premium could result in 20 extra Tcf of gas. This, in turn, could provide a net savings of $17 billion ($1982) to the ratepayer based on an average reduction in marginal cost of $0.84/Mcf.

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REFERENCES

1. Unconventional Gas Sources, The National Petroleum Council, 1980.

2. The adjustment factor for converting NPC costs to $1982 is 1.304; this was taken from: Ovid Baker, Unconventional Sources: U.S. Gas Options, presented at the Energy Bureau Conference on the Outlook for Natural Gas, October 18, 1982.

3. Over the period 1968-1980, the average real rate of return on owners equity in petroleum production and refining was estimated to be about 8% (Citibank Corporation. "Net income of Leading Manufacturing Corporations (by year)..." Economic Week [previously Economic Letter], April editions, 1969-1981). The NPC assumed a 15% real return on investment as a mean value for all prospects, based on 100% equity participation. In theory, a real return at this rate should account for some risk premium considered reasonable for developing tight sands gas and which exceeds requirements for lower or more normal risk operations. Some industry analysts believe that even this rate is low without considerable improvement in fracture diagnostics and performance predictability.

3. For blanket tight gas sands, the focal point of this paper, differences in technology specifications are specified below:

BASE CASE

Fracture Design Height	4 X Net Pay
Fracture Height Ranges	200 - 600 Ft.
Fracture Conductivity	500 Md-Ft.
Effective Fracture Length	
(a) Permeability G.T.0.1MD	1000 Ft.
(b) Permeability L.T.0.1MD	1000 Ft.
Field Development	4 Wells/Sec

ADVANCED CASE

Fracture Design Height	3 X Net Pay
Fracture Height Ranges	150 - 400 Ft.
Fracture Conductivity	1000 Md-Ft.
Effective Fracture Length	
(a) Permeability G.T.0.1MD	2000 Ft.
(b) Permeability L.T.0.1MD	4000 Ft.
Field Development	12 Wells/Sec

TABLE 1

NEAR-TERM DEVELOPMENT POTENTIAL - BASE TECHNOLOGY
NPC APPRAISED BASINS, $ 1982

	TOTAL GAS		RENT/Mcf		AT $6.52/Mcf RANKING BASED ON BLANKET AND LENTICULAR SANDS		RANKING BASED ON BLANKET SANDS ONLY	
	$6.52/Mcf (Tcf)	$11.74 (Tcf)	$6.52/Mcf ($1982/Mcf)	$11.72/Mcf ($1982/Mcf)	GAS	RENT/Mcf	GAS	RENT/Mcf
Northern Great Plains	76.7	79.8	0.182	0.382	1	6	1	5
Greater Green River	32.9	45.3	0.179	0.442	2	7		
Blanket Formations	6.2	7.6	0.129	0.329			2	6
Lenticular Formations	26.7	32.7	0.191	0.535				
Wind River	9.7	12.2	0.237	0.525	5	3		
Blanket Formations	1.1	1.2	0.118	0.333			9	7
Lenticular Formations	8.6	11.0	0.256	0.545				
Uinta	13.1	13.3	0.359	0.725	4	1		
Blanket Formations	3.2	3.4	0.219	0.412			5	2
Lenticular Formations	9.9	9.4	0.404	0.861				
Piceance	18.4	19.2	0.255	0.557	3	2		
Blanket Formations	1.8	1.8	0.222	0.444			6.5	1
Lenticular Formations	16.6	17.4	0.259	0.569				
Denver	--	1.3	--	0.100	10	9.5	8	9.5
San Juan	1.5	1.8	0.087	0.222	8	8	6.5	8
Val Verde	0.3	0.8	--	0.375	9	9.5	10	9.5
Edwards Lime	6.1	6.7	0.197	0.403	7	4	4	3
Cotton Valley	6.3	7.1	0.190	0.380	6	5	3	4

NOTE: $6.52 in 1982 dollars corresponds to $5 in 1979 dollars as used in the NPC report.

TABLE 2

BASIN RANKINGS AT RISK PREMIUMS OF 0%, 6%, AND 15%. NPC BASE CASE TECHNOLOGY, UNDERLYING COST OF CAPITAL = 8% RANKINGS BASED ON ECONOMIC RENT AT GAS SELLING PRICE OF $6.52 ($1982)/Mcf = $5/Mcf AS PUBLISHED BY NPC

	REFERENCE CASE PREMIUM = 6%		LOW RISK CASE PREMIUM = 0%		HIGH RISK CASE PREMIUM = 15%	
BASIN	RENT ($1982/Mcf)	RANK (LOW=10)	RENT ($1982/Mcf)	RANK (LOW=10)	RENT ($1982/Mcf)	RANK (LOW=10)
Northern Great Plains	0.182	5	0.465	5	0.068	3
Green River*	0.129	6	0.374	7	0.041	7.5
Wind River*	0.118	7	0.414	6	0.41	7.5
Uinta*	0.219	2	0.513	2	0.072	2
Piceance*	0.222	1	0.526	1	0.067	4
Denver	--	9.5	0.254	10	--	10
San Juan	0.087	8	0.346	9	0.029	9
Val Verde	--	9.5	0.371	8	0.055	6
Edwards Lime	0.197	3	0.472	4	0.074	1
Cotton Valley	0.190	4	0.484	3	0.058	5

* Blanket Unstacked Formations Only.

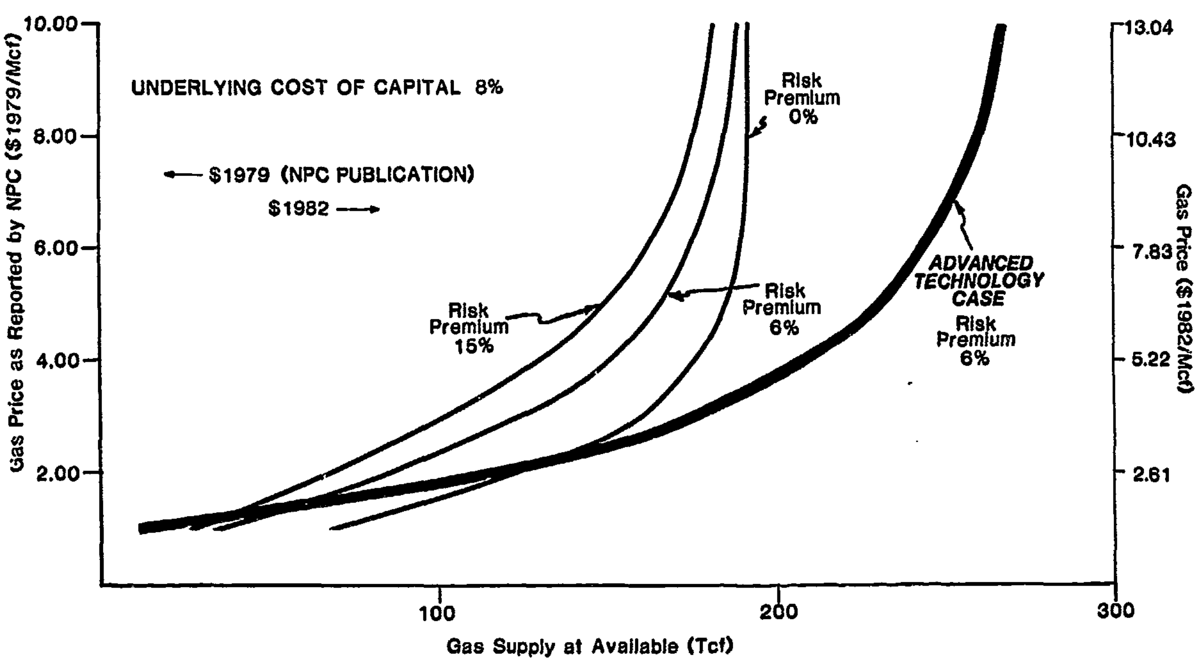

Figure 1: EFFECT OF RATE OF RETURN ON COST SUPPLY CURVES NPC BASE CASE TECHNOLOGY (Blanket and Lenticular Formations Combined)